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Changing the World's Energy Future

Charles Forsberg

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Idaho National Laboratory
Idaho Falls, Idaho 83415

http://www.inl.gov

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What is the long-term demand for liquid hydrocarbon fuels and feedstocks?

Charles Forsberg

Department of Nuclear Science and Technology, Massachusetts Institute of Technology, 77 Massachusetts Ave., Cambridge, MA, USA

HIGHLIGHTS

- U.S. oil consumption 18 million barrels per day.
- Uses: dense energy source, chemicals, energy storage, and radiative heat transfer.
- Very expensive to reduce liquid hydrocarbon demand below 10 million barrels per day.
- Option to replace all crude oil with cellulosic hydrocarbon drop-in fuels.
- Achieve atmospheric carbon dioxide reductions at an affordable cost.

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ABSTRACT

Liquid hydrocarbons made from crude oil serve many functions: (1) a dense, easy-to-store, easy-to-transport energy source, (2) a method for daily-to-seasonal energy storage, (3) a chemical feedstock, (4) a chemical reducing agent and (5) a method to enhance high-temperature heat transfer in many furnaces and industrial processes. Liquid hydrocarbons can be produced and used without increasing atmospheric carbon dioxide levels if made from non-fossil feedstocks such as carbon dioxide or biomass. Understanding future liquid hydrocarbon demand is the starting point in assessing the viability of such options. Our assessment is that U.S. demand for liquid hydrocarbons is unlikely to go below the equivalent of 10 million barrels per day of crude oil but could be as high as 20 million barrels per day. The costs to replace liquid hydrocarbons increases rapidly at lower liquid hydrocarbon consumption rates. Hydrocarbon biofuels from cellulosic feedstocks can meet such demands if produced with large external inputs of heat and hydrogen. Options based on more limited feedstocks (starches, plant oils, sugars, etc.) can't meet such demands.

1. Introduction

Unless we find a drop-in replacement for oil, we must not only replace oil but much of the U.S. infrastructure: pipelines, refineries, cars, aircraft, furnaces, chemical processes and a myriad of other systems. The development and deployment of liquid-hydrocarbon replacement technologies will take decades and trillions of dollars. *However, climate change (and probably the finite nature of oil supplies) must be effectively addressed on a significantly shorter timescale.*

Liquid hydrocarbons (gasoline, diesel, jet fuel, chemical feedstocks, etc.) are primarily made from crude oil with smaller quantities made from coal, natural gas and biomass. They are made from crude oil because it has been the lowest-cost feedstock. If crude oil had never existed, it is likely civilization would have invented these fuels and found feedstocks to produce them because of their useful properties. These hydrocarbons (C_xH_y) can be made in (1) unlimited quantities from natural sources of carbon dioxide (such as from air or ocean) and (2) large quantities from cellulosic biomass. In both cases, there is no net addition of carbon dioxide to the atmosphere. Carbon dioxide is removed from the atmosphere, converted into a hydrocarbon fuel, burnt and returned to the atmosphere. Stopping greenhouse gas emissions does not depend on whether we burn and use liquid hydrocarbons as fuels and chemical feedstocks. Stopping greenhouse gas emissions is about (1) changing the feedstocks used to produce liquid hydrocarbons or (2) finding replacements for the use of liquid hydrocarbons.

If carbon dioxide (CO_2) is the feedstock for production of liquid hydrocarbons, large quantities of hydrogen are required to remove the oxygen and add hydrogen to the carbon. If cellulosic biomass is the feedstock, there is a tradeoff between the amount of biomass and hydrogen needed to produce a unit of hydrocarbon liquid product. Recent studies [1,2] indicate the potential for the U.S. to produce up to 30 million barrels per day of liquid hydrocarbons from cellulosic

E-mail address: cforsber@mit.edu.

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biomass. As a point of comparison, the U.S. currently consumes 18 million barrels of oil per day. Cellulosic biomass is the most common form of biomass on earth and includes such materials as corn stover, wheat straw, trees and energy crops. The cost of hydrogen, not biomass, drives the cost of cellulosic liquid hydrocarbons production. This is without major impacts on food and fiber prices.

Different routes to decarbonization have different transition times and different costs. The starting point (this paper) is to understand the demand for liquid hydrocarbons and what part of that demand can be economically met with alternative technologies and where liquid hydrocarbons from alternative feedstocks are the preferred option.

2. Existing liquid hydrocarbon (oil) demand

In 2019, oil was 36.7 % of the primary energy input to the U.S. economy and supplied 48 % of the total energy input to the final customer [3]: transportation, industry, commercial and residential. If one can replace crude oil with alternative feedstocks to produce liquid hydrocarbons, one decarbonizes about half the U.S. economy. The primary use of fossil fuels is for energy production but included in those numbers are fossil fuels used as a feedstock for the production of various goods ranging from drugs to plastics. Many of these products contain carbon and a carbon containing feedstock is required. Today the primary chemical feedstocks are oil and natural gas. Fossil fuels are also used as a chemical reducing agent to convert materials such as iron ore into iron. Coal in the form of coke is the primary chemical reducing agent but natural gas and liquid hydrocarbons can be used. Fig. 1 shows the breakdown between the uses of fossil fuels in the U.S. industrial sector for energy versus these other uses of fossil fuels. About 6 % of total fossil fuel consumption is not for energy production. These non-energy uses of fossil fuels depend primarily upon the carbon in these fuels. When considering the future demand for liquid hydrocarbons, these uses are the energy equivalent of 2.4 million barrels of oil per day.

Table 1 shows the products produced from crude oil in the United States [5]. The largest single use is gasoline for transport, representing a demand of about 8 million barrels of crude oil per day. However, many other products are also produced; thus, the challenge is replacing all the hydrocarbon products produced from crude oil.

Table 1
Products Produced from Crude Oil in the United States.

Products (U.S.)	Consumption (10^6b/d)
Gasoline	8.034
Distillate fuel oil (diesel & heating oil)	3.776
Hydrocarbon gas liquids (HGLs)	3.197
Kerosene-type jet fuel	1.078
Still gas	0.611
Asphalt & road oil	0.342
Petrochemical feedstocks	0.286
Petroleum coke	0.260
Residual fuel oil (Shipping)	0.217
Miscellaneous products & other liquids	0.152
Lubricants	0.100
Special napthas	0.045
Aviation gasoline	0.011
Kerosene	0.008
Waxes	0.004
Total	18.120

3. Liquid fuel transport demand

Liquid hydrocarbon fuels are used in transportation because of their high energy density per unit volume and mass compared to any other class of chemicals that exist as liquids at near atmospheric pressure and temperature. The high energy density of liquid fuels is a result of two characteristics. First, the H—C—H bond incorporates hydrogen in its high-density chemical form. The average atomic weight per atom of that three-atom structure is 4.7 versus the next lightest element lithium with an atomic weight of 7. There is a large energy release by oxidation of three atoms versus one atom. Second, the oxygen for combustion of hydrocarbon fuels comes from the atmosphere. It is not required to transport oxygen to the place where combustion occurs. In contrast, a lithium battery contains the lithium, a transition metal such as cobalt, and oxygen—plus large amounts of other materials to avoid having the fuel and oxidizer accidently combust inside a sealed package. No improvement in battery technology can eliminate the massive advantage of liquid hydrocarbons as a high-density energy source.

Carbon-based liquid fuels like diesel and jet fuel have remarkable properties including high energy density, safety in handling and low-cost long-term storage. There are severe economic penalties involved in transitioning from hydrocarbon fuels to batteries or other energy sources in aircraft or heavy trucks where an added kilogram of fuel necessarily requires one less kilogram of cargo. Aircraft have the added constraint of large penalties in fuel economy [6] if use a low-density fuel such as hydrogen that increases aircraft size and air friction that, in turn, reduces fuel economy. Aviation consumes about a million barrels per day and diesel fuel consumption is the equivalent of about 3 million barrels of oil per day.

For these two markets (aircraft and heavy trucks) in a low-carbon world, the users will be willing to pay a large premium for liquid hydrocarbon fuels made from non-fossil sources rather than use alternative energy sources. That sets the minimum demand in the U.S. for hydrocarbon liquids as fuels at several million barrels per day over the next several decades—given the growth of the heavy truck and aircraft industries. The opposite in terms of transport fuel requirements are ships and railroads where weight is not a major constraint enabling the potential use of other energy sources.

The largest U.S. crude oil market is for cars and light trucks—about 8 million barrels per day of oil equivalent in the form of gasoline. The continued efficiency improvements in cars and trucks [7] reduces this demand over time. The future light-duty vehicle fuel options [8] include (1) replacement of fossil-fuel gasoline with biofuels or hydrogen, (2)

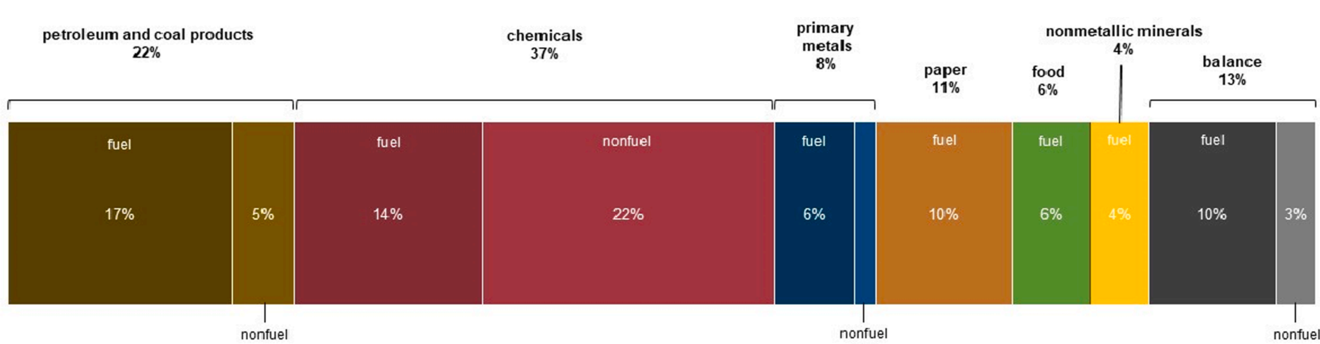

Fig. 1. Manufacturing energy fuel and nonfuel consumption by industry, 2018 (%) [4].

hybrid vehicles, (3) plug-in hybrid vehicles and (4) all-electric vehicles. Hybrid vehicles burn some type of fuel and have batteries on-board. When the vehicle slows down or goes down the hill, the battery is charged. When the vehicle accelerates or goes up the hill, the battery provides power. The battery enables the engine to operate in its most efficient modes most of the time. It has been estimated that an all-hybrid fleet could reduce gasoline consumption by about 30 %.

Plug-in hybrid vehicles have a heavier battery package that enables the vehicle to go on shorter trips without using the combustion engine and to recharge by plugging into the electrical grid. A combustible fuel is used on longer trips. The owner can use fuel or electricity depending upon their relative prices or availability of electricity. All-electric vehicles have larger battery packages to enable longer distances and significantly higher costs partly driven by the costs of raw materials in the batteries.

The choice of vehicle technology has massive economic and social implications. Internal combustion engine (ICE) vehicles have the lowest initial costs while all-electric vehicles have the highest costs. Most of the ownership cost of cars is the initial cost of the vehicle—the fuel costs are a smaller fraction of lifetime ownership. This is in contrast to aircraft and heavy-haul trucks where fuel costs are a large fraction of total costs. Social decisions to electrify light vehicles reduces the standard of living for those in the lower 60 % of incomes because the primary expenditure is in the vehicle, not the fuel.

Unless there are radical changes in battery chemistry (sodium sulfur, aluminum sulfur or other earth-abundant battery chemistries), electric vehicles will remain significantly more expensive than ICE vehicles because of the much larger quantities of higher-priced materials such as lithium, nickel, and cobalt in battery systems. A recent International Energy Agency report [9] estimated the increase in demand of these elements over the next 20 years with lithium demand increasing by a factor of 42, cobalt demand increasing by a factor of 21 and nickel demand increasing by a factor of 19. Historically the lead time for a new mine is 10 years. Separate from the question of whether such massive increases in mining are possible even if most restrictions on mining are removed, such increases in demand will result in significantly higher prices. Light vehicles with ICEs are cheap to manufacture because they are made of earth-abundant low-cost materials—mostly steel (iron and carbon), plastic (carbon and hydrogen) and glass (silicon oxide [sand] and sodium oxide). With only a small number of exceptions, the cost of any material is inversely proportional to its abundance in the earth's crust. To achieve a middle-class life style for the earth's population [10] requires using earth-abundant elements in major systems such as transportation. If use less abundant elements, the costs increase as scale up to ultimately meet the requirements for 8 to 10 billion people. Lithium-ion car batteries are made of relatively non-common elements that result in significantly higher costs than ICEs and limits their use to a small fraction of the global population.

The battery cost challenge is seen in the EIA [11] surveys of the total capital cost of installed utility storage battery systems over time [Fig. 2]. The capital cost has leveled off above $500/kWh. The earlier decreases in capital costs were primarily driven by improved technology, scaling up production and the associated learning curves. The leveling off in capital costs partly reflects the larger fraction of total costs associated with the materials of construction in the batteries. The expectation is for increased costs going forward in time because of increases in battery material costs.

Plug-in hybrid electric vehicles and all-electric vehicles obtain much of their energy from the electricity grid; thus, their economics must include the impacts on the grid. The two vehicle types have radically different impacts on electricity costs delivered *to all customers*—not just vehicle owners [12].

Fig. 3 shows the cost breakdown for delivered electricity in the United States. About 40 % of the delivered cost of electricity is associated with transmission and distribution [13], the balance is in the cost of electricity production. If the additional electricity demand occurs at

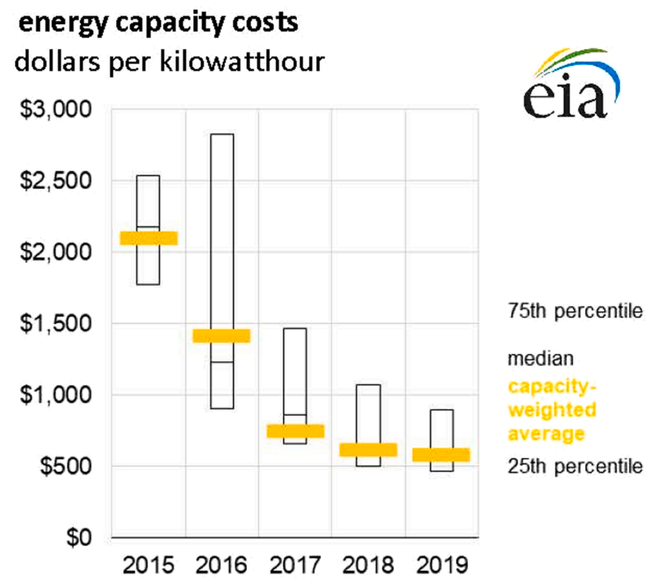

Fig. 2. Total Installed Battery Costs for Large-scale Systems in the United States [11].

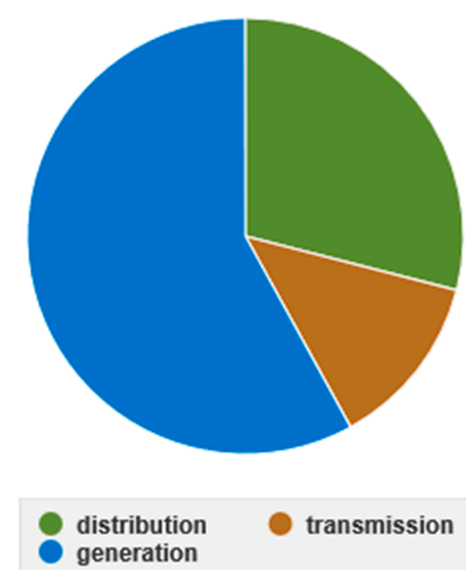

Fig. 3. Cost Breakdown of Delivered Electricity to the Customer in the United States in 2019 [13].

times of existing peak electricity demand, large expansions of the electricity grid are needed that increase electricity prices for *every customer*. In contrast, if there is added electricity demand from light vehicles at times of low total electricity demand, the average price of electricity may go down because the grid is delivering more electricity to the customer without grid expansion. The fraction of the cost of delivered electricity from building and maintaining the grid goes down.

From the perspective of the electricity grid, there is a major difference between all-electric vehicles and plug-in hybrid electric vehicles. With a plug-in hybrid vehicle, there is assured transportation for the vehicle owner if the battery is not charged by burning a combustible fuel. It is viable to limit recharging to times of lower electricity demand resulting in greater utilization of the transmission/distribution system and thus lowering the average cost of delivered electricity for all electricity customers. In this context, a recent study [14] examined likely times when electric vehicles will be recharged and found that most recharging will be done in the early evening shortly after the sun sets—the time of peak daily electricity demand (Fig. 4). This recharging pattern is partly caused by work schedules and single car families that want assured car availability. Such an all-electric vehicle future can result in an expensive electricity system for every-one because the recharging (Fig. 4) increases the peak electricity demand with major increases in the cost of the electricity distribution system (Fig. 3) that is sized based on peak demand—not total electricity produced.

There are other effects of all-electric vehicles in cold climates. With internal combustion engines, heat for the passenger compartment is provided by the engine—waste heat to warm the passengers and defrost windows is provided at no additional cost or loss of range. With all-electric vehicles heat must be provided by batteries, thereby increasing peak vehicle electricity demand at times of peak winter electricity demand for other uses, combined with minimum solar and in some areas wind electricity production. At the same time, there are efforts in parts of the United States to electrify heating and cooling. Any electrification of heating will show up on the coldest weeks of the year at the same time of peak demand for all-electric vehicles.

A recent review [12] of the many studies on all-electric vehicles concluded “Overall, a complete benefit-cost assessment, even at the regional scale, is still missing that considers the entire extent of values, enablement costs, and the perspectives of all stakeholders, including the utilities, EV owners, charging station owners and rate payers.” In this context, the recent U.S. National Academy of Science study [7] and state/national policies do not generally consider impacts on the electricity grid while considering impacts of electrified light-vehicles. This is not an issue if there are only a few million all-electric vehicles; but, it may become the primary challenge if all-electric vehicles become the primary type of light-duty vehicle. From the perspective of the electricity grid, an all-electric vehicle fleet in many locations implies large grid and power plant capacity expansion to meet a peak demand and likely major increases in electricity prices to all customers. This is location dependent because there are large variations in electricity grids. The challenge may be small in Norway with massive hydroelectric capacity but a major challenge in parts of the southern United States with air conditioning loads that extend far into the night and at times of cold weather in northern parts of the United States.

Plug-in light-duty hybrid vehicles avoid most all-electric vehicle challenges because they combine the cheap storage capabilities of liquid hydrocarbon fuels with the capability to recharge much smaller batteries when low-cost electricity is available. Their use relative to ICEs would reduce light-vehicle fuel demand by two thirds (consume 2–3 million barrels per day of liquid fuels). Given the expected cost impact of all-electric vehicles, this defines the likely minimum future gasoline demand for the U.S. before large increases in light-vehicle ownership costs.

4. Energy storage demand

Fossil fuels provide two primary functions: (1) an energy source and (2) a low-cost energy storage system that enables energy production to better match energy demand. The storage challenge may create a major long-term demand for cheap-to-store liquid hydrocarbons. We use about 100 quads of energy per year in the U.S. with about 6 weeks of stored energy with more energy storage in the winter and less in summer. U.S. energy storage includes a 90-day supply of oil, a 30-day supply of natural gas, over a 100-day supply of coal and 6–9 months of nuclear fuel in reactors. The large oil inventory includes the Strategic Petroleum Storage reserve operated by the U.S. government to minimize economic damage in the case of an oil supply disruption. Energy storage addresses daily to seasonal changes in energy demand while providing assured energy in the face of hurricanes, earthquakes, and multi-week weather events. Six weeks of storage is 3.4 million GWhs; that is, the U.S. storage requirements are measured in millions of gigawatt-hours [15]. A million gigawatt hours requires about 1.8 million barrels of oil equivalent per day.

To understand the scale of the energy storage challenge, consider options to provide a million gigawatt hours of storage for the electric sector. The U.S. Energy Information Agency [11] reports installed costs of utility-scale battery systems over time with costs leveling off near $500/kWh [Fig. 2]. A million gigawatt hours of storage is $500 trillion—about 20 times the size of the U.S. economy. Today 99 % of U.S. electricity storage is hydroelectric pumped storage—553 GWh [16]. The costs are substantially less than batteries [17]. If we use hydro pumped storage, we would need to expand the total U.S. pumped storage capacity by a factor of 1800 for a million gigawatt hours of electricity storage. Suitable sites are not available for such a large increase in

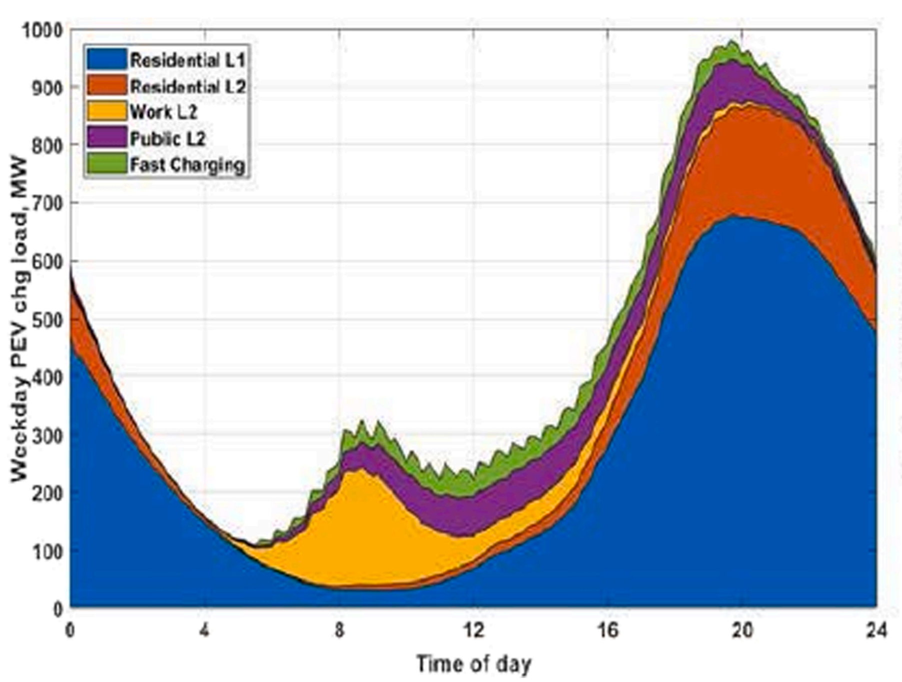

Fig. 4. Projected California plug-in electric vehicle electricity demand 2017–2025 vs time of day.

energy storage capacity.

The addition of non-dispatchable wind and solar may dramatically increase storage requirements in the electric sector. The U.S. Energy Information Agency [18] has estimated the levelized cost of electricity for solar ($31.30/MWh), on-shore wind ($31.45/MWh) and offshore wind ($115.04/MWh) in good locations. The levelized cost of short-term storage using batteries is $121.86/MWh—about four times higher than the cost of making electricity. Today stored natural gas burned in gas turbines with low storage costs enables wind and solar by avoiding the high cost of battery systems while providing assured supplies of electricity. Wind and solar operate as fuel savings technologies [19]. The question is what replaces natural gas in its role as stored energy—one option is the use of liquid hydrocarbons in gas turbines. Many utility gas turbines use liquid hydrocarbons to backup natural gas that may not be available when low temperatures because the natural gas is reserved for home heating.

Separately there is the seasonal storage challenge. In the United States most of the heating demand is met by burning natural gas. As shown in Fig. 5, the peak monthly demand for natural gas in January over the base-load demand for natural gas is about equal to the total electricity production [20]. There is about a factor of two difference in solar output at the mid-latitudes [21] between summer and winter. This implies a massive added seasonal impact on energy storage requirements if any significant amount of the heating load is provided by electricity from solar. Today the seasonal storage challenge is met by fossil fuels, primarily natural gas. If cheap-to-store liquid hydrocarbons replace any significant fraction of this demand, it implies a major increase in liquid hydrocarbon demand.

From a broader perspective, in a low-carbon world, there are only four affordable energy storage options at the million-gigawatt hour scale [15].

Nuclear fuel. Most nuclear reactors are refueled every 18 to 24 months in the United States. Reactors have massive quantities of energy storage in the form of nuclear fuel.

Gaseous fuels. A large fraction of the hourly to seasonal variations in energy demand is met by natural gas stored in massive underground storage facilities that decouple steady-state production from demand. The first well-documented use of gaseous fuel was for town lighting that occurred in 1807 in London and rapidly expanded to major cities around the world. This gas was “town gas”—a mixture of hydrogen and carbon monoxide made from gasification of coal with gas storage facilities built into these systems. Town gas was soon used for cooking in homes and other purposes. Natural gas did not fully replace town gas until the 1950s in the United States and the 1970s in Great Britain. The projected path forward by many experts is a conversion of gaseous fuels to hydrogen that can use the same underground storage systems [20,22].

Liquid hydrocarbon fuels. This is the primary form of energy storage for the transport sector but also a storage mechanism for heating demand and electricity production.

Heat storage. Heat storage has not been historically used on a large scale because of the availability of storable fossil fuels, but heat storage may become important in a low-carbon economy. The heat source for storage can be nuclear, concentrated solar power or low-price electricity converted to heat.

Systems [23] have been developed (Fig. 6) that integrate heat storage, liquid hydrocarbons, and hydrogen with electricity generation. Such systems are used in some existing concentrating solar power (CSP) plants and are planned for advanced nuclear plants. The first nuclear power plant with heat storage will be the General Electric/Terrapower Natrium reactor to be built in Wyoming (U.S.) by the end of this decade. Cold fluid from heat storage is heated by a nuclear reactor or CSP facility with hot fluid sent to a hot storage tank. Hot fluid from the storage tank is sent to the power block to produce electricity and/or to supply industrial heat users. Typically, the heat storage fluid is nitrate salt that has a peak allowable temperature slightly below 600 °C. Storage capacities are measured up to several gigawatt hours. The peak power block output may be several times the peak output from the nuclear or CSP facility. If very low-price electricity is available, it can be converted into stored heat for later use. Seasonal peak demands can be met by using energy sources such as liquid hydrocarbon fuels and hydrogen to heat the storage fluid.

There are two classes of seasonal heat storage systems—both early in the development cycle. Very low-costs are required for a system that cycles heat once or twice a year. All systems in this class use rock as the heat storage material—other heat storage materials are too expensive. The minimum storage capacities are measured in tens of gigawatt hours per system. To keep heat losses down, the system sizes must be large to minimize the external surface area (heat losses) that increase as the square of the dimensions to heat storage capacity that increases as the cube of the dimensions. The large minimum sizes limit use to power systems and large heat users. This categorization excludes ground-source heat pumps where electricity is used to pump heat from the ground heat sink to the customer—in these systems inputting energy (electricity) is used to obtain heat.

The first set of options [24] are geothermal heat storage systems where pump hot water or super-critical carbon dioxide deep underground to heat a zone of rock and reverse the process to recover the heat. The round trip efficiencies are low. That is partly because can’t insulate a piece of rock hundreds of meters on each side that is hundreds of meters underground. Heat conducts out from the heat storage zone.

The second set of options [25,26] use large piles of crushed rock that are 20 to 40 m high and many football fields in area inside insulated buildings similar to aircraft hangers. Heat is transferred to and from the crushed rock using nitrate salt (to 600 °C) or oil heat transfer fluids (to 400 °C). Heat is added by spraying hot fluid on top of the crushed rock that heats the rock as it trickles downward by gravity to the drain pans below the crushed rock. Heat is recovered by sprinkling cold fluid on top of hot crushed rock where the fluid is heated trickling through the

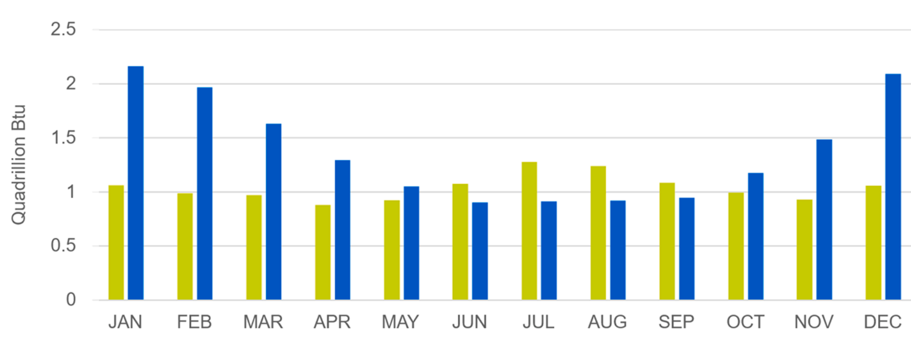

Fig. 5. 2020 U.S. Electric (left, green bars) and Natural Gas (right, blue bars) Consumption across All Customer Sectors. Courtesy of the American Gas Association [20]. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

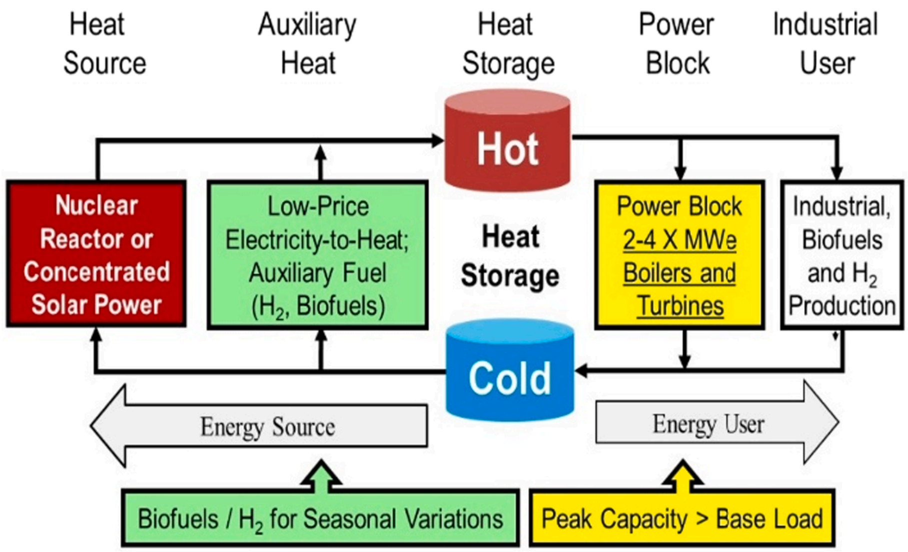

Fig. 6. Variable Heat and Electricity with Heat Storage to Match Production with Demand.

crushed rock to the drain pans below. Most of the void space in the crushed rock is filled with the cover gas when the fluid is trickling downward—the liquid is a small fraction of the void space. These Crushed Rock Ultra-large Stored Heat (CRUSH) systems have potentially high round trip efficiency but are at the early stages of development. High quality insulation can reduce heat losses to the environment and one has better control over rock properties compared to geological heat storage.

Many industrial applications such as glass and cement production require very high temperature heat. One new heat storage technology at the early stage of commercialization [27–29] can store heat at low costs at the flame temperatures of natural gas – 1800 °C. Firebrick Resistance Heated Energy Storage (FIRES) converts electricity into stored heat using conductive (doped) firebrick as the resistance heater. Traditional firebrick is an electrical insulator. Firebrick, as used in steel, cement and glass furnaces, is the only low-cost material that survives high temperature environments and thus the only high-temperature heat storage option for oxidizing environments. FIRES enables converting electricity to high-temperature heat at times of low electricity prices to provide heat for industry or high-temperature gas turbines providing peaking electricity. There are different types of firebrick but all are made out of high-temperature oxides such as magnesium oxide, silicon oxide and aluminum oxide.

Today in the United States, crude oil provides 36.7 quads of the energy while natural gas provides 32.1 quads and coal provides 11.4 quads. If any significant fraction of the energy and storage functions of natural gas or coal is moved to liquid hydrocarbon fuels, it results in much larger demands for liquid hydrocarbon biofuels. The likely competition in these energy/storage markets are (1) heat storage that has not been developed on a large scale and (2) hydrogen as a replacement for natural gas and coal—a second gaseous fuel transition.

5. New markets

Fossil fuels are embedded into our industrial economy to meet requirements that are not generally recognized to exist. We have identified one such “new” market. There may be other markets that have not been recognized and that represent a hidden demand for liquid hydrocarbons.

The high-temperature heat demands (>500 °C) of industry are primarily met by burning fossil fuels. Most energy studies assume that future high-temperature heat needs will be provided by electrical heating or burning of hydrogen. However, in most high-temperature processes, heat is partly or primarily transferred from the burning fuel to the colder object via radiative heat transfer—such as in glass furnaces. Radiative heat transfer makes a campfire feel warm and is enabled by carbon particles in the flame, which convert heat energy into a form that can be radiated to the person. Radiative heat transfer is not important at lower temperatures (building heating, stoves, etc.) where heat is transferred by conductive and convective mechanisms.

In contrast, if hydrogen is burned or air is electrically heated, there is little in the hot gases to quickly and efficiently convert that heat into radiant heat. In hydrogen facilities, this creates a safety challenge [30] where burning hydrogen from a leak may not be visible. Special sensors are used to detect burning hydrogen to prevent people from walking into invisible flames.

Some carbon may need to be added to hydrogen [31] or electrically heated hot air in high-temperature applications to improve high-temperature heat transfer from non-fossil energy sources to whatever is being heated. The quantities of hydrocarbon fuels required for such uses is not well understood.

6. Liquid hyrodcarbons from non-fossil sources

Liquid hydrocarbon fuels may be made from different carbon feedstocks with no net carbon dioxide emissions to the atmosphere. There are two questions for any option. First, what are the economics? Economics is relative to alternative solutions. Second, is there sufficient feedstock to produce these quantities of liquid hydrocarbons? The assessment above (Table 2) is that the minimum liquid hydrocarbon demand for the United States in a low-carbon world is near 10 million barrels of oil equivalent per day (chemical feedstocks, aircraft and heavy trucks, plug-in hybrid vehicles, other). Below 10 million barrels per day, the alternatives to liquid hydrocarbons (fuels and chemical feedstocks) become much more expensive. Under some circumstances the demand could be as high as 20 million barrels of oil equivalent per day. The higher estimates of liquid hydrocarbon demand occur when constraints on (1) vehicle electrification including plug-in hybrid vehicles because

Table 2
Future U.S. Demand for Liquid Hydrocarbons.

Liquid Use	Equivalent 10^6 Barrels/day
Chemical Applications	2.4
Trucks/Aircraft	4.0
Light Vehicles	2 to 3
New Uses/Other	1.0
Energy Storage	6.1

of increasing costs for battery materials or electricity and (2) replacing some of the energy and energy storage functions of natural gas and coal.

Hydrocarbon liquids are made today in limited quantities from biomass. Plants remove carbon dioxide from the air to produce biomass. The biomass can be converted into hydrocarbon liquid fuels. When the fuels are burnt, the carbon dioxide is released to the atmosphere. There is no net addition of carbon dioxide to the atmosphere. Today most biofuels (hydrocarbons and partly oxidized hydrocarbons such as ethanol) are made from starches (corn) vegetable oils (soybeans) and sugar (sugar cane). The available feedstocks are limited and the use of these feedstocks competes with the demand for food. Biofuels can be made from cellulosic biomass (corn stover, trees, energy crops, etc.)—the most abundant form of biomass on earth. The estimates are that with traditional biofuels processes, a third of U.S. liquid fuel demand could be met [32]—about 6 million barrels of oil per day.

There are other biofuels options [1,2,33]. For the U.S., it is estimated that up to 30 million barrels per day of liquid hydrocarbons can be produced from cellulosic biomass assuming massive addition of external heat and hydrogen at the refinery. This option can fully replace crude oil domestically and globally (~100 million barrels per day) without major impacts on food or fiber prices. It requires using cellulosic biomass as a carbon feedstock, not as an energy source to drive the conversion process from cellulosic biomass to a liquid hydrocarbon.

Historically the conversion of biomass into biofuels involved using the carbon in the biomass for four purposes: (1) the source of carbon in the hydrocarbon product, (2) a source of carbon to remove the oxygen from biomass as carbon dioxide, (3) a source of energy and feedstock to produce hydrogen required in the final product and (4) an energy source to operate the process. Biomass is 40 % oxygen by weight, thus much of the carbon feedstock is for removal of the oxygen. The above description is true whether one (1) gasifies the biomass and uses the Fischer-Tropsch process to produce liquid hydrocarbons or (2) uses fermentation to produce ethanol that is then converted into a liquid hydrocarbon. The consequence is there is insufficient biomass to globally replace hydrocarbon fuels using this strategy without major impacts on food and fiber prices.

The alternative option is to treat cellulosic biomass (corn stover, forest wastes, energy crops, etc.) as a carbon feedstock to provide the carbon in the final product and add massive quantities of external heat and hydrogen in the production process. External hydrogen removes the oxygen as water and provides the hydrogen in the hydrocarbon product. Hydrogen can be produced from natural gas with sequestration of the carbon dioxide, high-temperature (steam) electrolysis using nuclear energy and electrolysis with wind or solar inputs. It would be shipped via pipeline to the bio refinery. The massive quantities of heat are the primary energy input to operate the processes. Heat would most likely be supplied with nuclear reactors co-located with the biofuels plants. With this strategy, there is sufficient cellulosic feedstocks to replace all crude oil without major impacts on food and fiber prices. The cost structure is very different from traditional biofuels production. The largest cost associated with cellulosic hydrocarbon liquid production is the hydrogen used in the process, not the biomass. Projected costs are near $70/barrel assuming hydrogen at $2/kg.

In the U. S., the future cellulosic hydrocarbon fuel production could be as high as 30 million barrels per day. First, the quantity of hydrocarbon fuel more than doubles per unit of biomass feedstock. Second, there are many biomass feedstocks (prickly pear, kelp, etc.) that are economic sources of carbon but not energy sources. Third, when biomass is no longer the primary cost in biofuels, one can pay more for biomass that creates new sources of biomass. For example, one can double crop (two crops per year) in the U.S. Midwest corn belt to produce biomass for biofuels fall-to-spring while producing corn in the summer. At one time, there was double cropping to provide food for horses in addition to corn and other crops. With the introduction of the tractor, the horses disappeared and there was no incentive to grow a second crop each year.

Fig. 7 shows the system design. The central component is the large integrated refinery that in many cases will be an existing refinery with modified front-end operations. Front-end processes convert biomass feedstocks into crude biofuels that are then refined to produce the final liquid hydrocarbons. Hydrogen is delivered via pipeline. In a world with constraints on carbon dioxide releases to the atmosphere, refinery heat input is likely to be from nuclear reactors because such refineries require gigawatts of high-temperature steady-state heat. Existing refineries consume about 10 % of the feedstock to provide heat. Many bio feedstocks contain added water that will boost heat demand. In this context, Dow and X-Energy have initiated work to build high-temperature reactors to provide heat to one of the Dow chemical plants in Texas. Similar arrangements are likely for refineries with similar heat demands.

The primary production route for hydrogen today is from natural gas with the byproduct carbon dioxide released to the atmosphere. The U.S. currently produces about 10 million tons of hydrogen per year used in oil refining, the chemical industry and production of fertilizer. In the United States with low-cost natural gas, the low-cost source of hydrogen is conversion of natural gas into hydrogen with sequestration of the byproduct carbon dioxide. Because of recent changes in U.S. law, there have been many announcements to build such plants with systems designed to sequester up to 98 % of the carbon dioxide. Recent assessments [34] show that the greenhouse emissions of a properly designed system approach that of green (wind and solar) hydrogen because of the large embedded carbon dioxide content in building wind and solar systems with associated electrolyzers. Recent reviews [35] show the available geological capacity for sequestration of carbon dioxide far exceeds potential needs. If the United States was to produce 10 million barrels per day of cellulosic hydrocarbons, the natural gas input would be greater than 25 % of current natural gas consumption.

The low density of biomass makes it uneconomic to ship long distances to refineries. Local depots are required to convert local cellulosic biomass into an economically shippable commodity to the refineries. There are three mainline options where the option will depend upon the specific biomass feedstock and refinery requirements. First, biomass can be pelletized to increase its density by a factor of ten. Pelletization is a commercial process to ship (1) wood chips to furnaces and boilers and (2) some types of animal foods. Second, anaerobic digestion converts biomass into methane and carbon dioxide. This is the source of renewable natural gas [36]. The methane carbon-dioxide mixture can also be converted into liquid hydrocarbon fuels. This process is commercial for some but not all types of biomass. The third option is flash pyrolysis, the fast heating of dry biomass that produces a bio-oil for the refinery and a pyrolysis solid. The process is commercial on a small scale in Europe. Depots may have many other functions. For example, crops such as alfalfa have leaves with protein that are high-quality animal food but stems with low value. Depots will likely separate the more valuable components in biomass for animal food and other purposes while sending lower-value components to the refineries.

These systems also enable large-scale negative carbon emissions. Cellulosic processing options such as flash pyrolysis and anaerobic digestion generate hydrocarbons with char or digestate that can be recycled to the soils to recycle nutrients and sequester carbon in the soil. Unlike food and fiber production, such biofuels options enable a much more sustainable agriculture and forest industry. That is because when growing food we mine soil for essential nutrients such as potassium and phosphorous in food. With hydrocarbon liquids production, these materials are unacceptable in hydrocarbon fuels creating the option for full recycle of nutrients to the soils. The addition of refractory carbon to the soils improves soil. The carbon retains moisture, helps retain nutrients in the soil and provides other benefits beyond sequestering carbon from the atmosphere. The total system, including carbon dioxide releases from hydrogen production, enable negative carbon emissions.

At the refinery, the intermediate biomass commodities (liquids, solids and gases) are processed into a bio-crude oil by flash pyrolysis (unless pyrolysis is done at the depot), direct hydrogenation of biomass

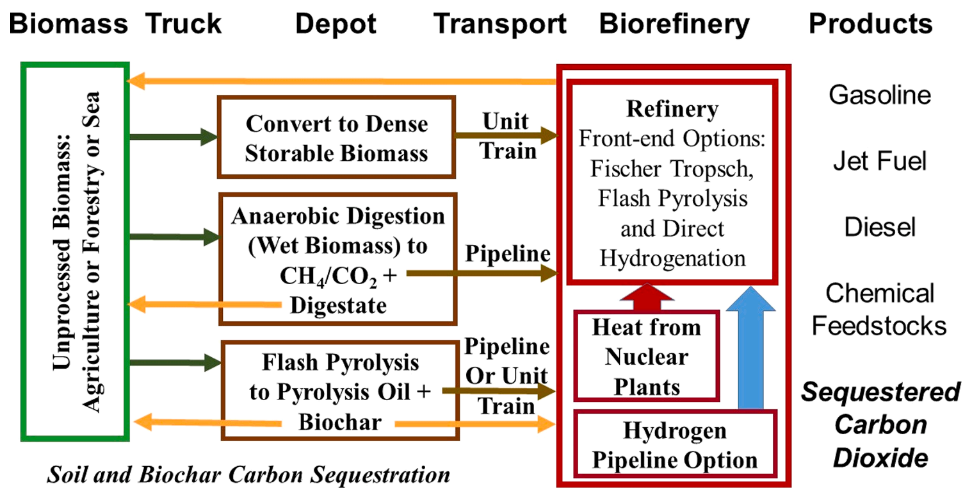

Fig. 7. Cellulosic Liquid Hydrocarbons System.

[37] or by the Fischer-Tropsch (FT) process. The bio crude oil would then be converted into hydrocarbon products by traditional refinery processes. Large integrated refineries [38] have the capabilities to rearrange molecules to provide functionally the same products as from crude oil. In the last several decades the health impacts of using liquid fuels have dramatically decreased because this capability removed impurities such as sulfur and rearrange hydrocarbon molecules to reduce the concentrations of the more toxic components such as benzene. Hydrocarbon fuel properties are improving with time [39].

Refineries can make tradeoffs between inputs of hydrogen and biomass and outputs of different hydrocarbon liquids and carbon dioxide. With a market for sequestered carbon dioxide, sequestered carbon dioxide becomes another refinery product similar to gasoline, diesel and jet fuel. At times of low biomass feedstock or low liquid hydrocarbon prices, the refineries would sequester more carbon dioxide. A market for sequestered carbon dioxide (negative carbon emissions) creates a powerful mechanism to minimize large swings in the prices of biomass feedstocks and liquid fuel prices. Recent legislation in the United States provides an incentive of $85/ton for sequestration of carbon dioxide.

This system may enable a rapid transition to a low-carbon world because it enables use of existing refineries and the natural gas system that becomes a hydrogen production system. Today, refineries buy different types of crude oil and blend those crude oils to produce a feed that matches their capabilities. This reduces the cost of crude oil. Refineries would incrementally convert from crude oil to bio feedstocks. We are seeing the very beginnings of this strategy. Multiple refineries are accepting small quantities of crude bio-oils, blending them with crude oil and refining the mixture into gasoline, diesel and jet fuel. In the United States, there are multiple announcements to produce blue hydrogen (hydrogen from natural gas with sequestration of the carbon dioxide) for the refinery and chemical industries.

The alternative liquid hydrocarbon production options are electric fuels [40–42] where natural sources of carbon dioxide are converted into liquid hydrocarbon fuels using massive amounts of hydrogen. This includes carbon dioxide from the air or water. This is technically viable; but, costs are estimated to be much higher because much more hydrogen is required and the cost of recovering carbon dioxide from air or water with low concentrations of carbon dioxide.

In a low-carbon future, hydrogen is a major energy carrier where the energy can be delivered to the final customer in the form of liquid hydrocarbon fuels or hydrogen. With the hydrocarbon biofuels, some of the energy is from the biomass carbon and some is from the hydrogen added at the refinery. In the near-term, the economic source of hydrogen will be conversion of natural gas into hydrogen with sequestration of the carbon dioxide.. The cellulosic liquid hydrocarbon systems have large negative greenhouse gas emissions; thus, the total system has negative carbon emissions when accounting for greenhouse gas emissions from hydrogen production and other miscellaneous sources.

7. Conclusions

The U.S. Energy Information Agency [43] business-as-usual case for the United States shows small changes in total liquid hydrocarbon demand between now and 2050. The International Energy Agency [44] states "But almost half of the emissions reductions achieved in the NZE [Net Zero Emission] in 2050 come from technologies that today are at the demonstration or prototype stage." The technological and economic challenges to develop and deploy alternative non-liquid hydrocarbon fuel technologies to replace crude oil are large.

Our assessment is that the minimum liquid hydrocarbon demand for the United States in a low-carbon world is near 10 million barrels of oil equivalent per day (chemical feedstocks, aircraft and heavy trucks, plug-in hybrid vehicles, other) but under some circumstances the demand could be as high as 20 million barrels of oil equivalent per day. This assumes that there are large policy and financial incentives to minimize crude oil consumption. Pushing liquid hydrocarbon demand below 10 million barrels per day will be very expensive given the costs of alternative technologies. The higher estimates of liquid hydrocarbon demand occur when constraints on (1) vehicle electrification including plug-in hybrid vehicles because of prices for battery materials or costs to the electricity grid and (2) replacing some of the energy and energy storage functions of natural gas and coal.

Large hydrocarbon liquid fuel demands limit viable options for low-carbon liquid hydrocarbon fuel production. In terms of biofuels, such quantities [1,2] are only possible if (1) the feedstock is abundant cellulosic biomass and (2) there are massive inputs of hydrogen and heat at the refinery for efficient use of the carbon feedstock. Liquid hydrocarbons from cellulosic biomass enable large-scale negative carbon emissions. If liquid hydrocarbons are made from natural carbon-dioxide sources, one needs a very large resource base such as the atmosphere or seawater—secondary carbon dioxide feedstock resources are insufficient. The costs of hydrocarbon liquid fuels from these carbon dioxide feedstocks is substantially greater than from biomass because of the greater energy input to capture and convert carbon dioxide into liquid hydrocarbons.

Author contribution

CF originated and wrote the paper.

CRediT authorship contribution statement

Charles Forsberg: Conceptualization, Formal analysis, Investigation, Methodology, Writing - original draft, Writing - review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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